

Chapter 3 Generators

3-1. General

a. Design constraints. Almost all of the hydraulic-turbine-driven generators used in Corps' powerhouses will be synchronous alternating-current machines, which produce electrical energy by the transformation of hydraulic energy. The electrical and mechanical design of each generator must conform to the electrical requirements of the power distribution system to which it will be connected, and also to the hydraulic requirements of its specific plant. General Corps of Engineers waterwheel generator design practice is covered by the Guide Specification CW-16210.

b. Design characteristics. Since waterwheel generators are custom designed to match the hydraulic turbine prime mover, many of the generator characteristics (e.g., short-circuit ratio, reactances) can be varied over a fairly wide range, depending on design limitations, to suit specific plant requirements and power distribution system stability needs. Deviations from the nominal generator design parameters can have a significant effect on cost, so a careful evaluation of special features should be made and only used in the design if their need justifies the increased cost.

3-2. Electrical Characteristics

a. Capacity and power factor. Generator capacity is commonly expressed in kilovolt-amperes (kVA), at a given ("rated") power factor. The power factor the generator will be designed for is determined from a consideration of the electrical requirements of the power distribution system it will be connected to. These requirements include a consideration of the anticipated load, the electrical location of the plant relative to the power system load centers, and the transmission lines, substations, and distribution facilities involved. (See paragraph 3-2f).

b. Generator power output rating. The kilowatt rating of the generator should be compatible with the horsepower rating of the turbine. The most common turbine types are Francis, fixed blade propeller, and adjustable blade propeller (Kaplan). See detailed discussion on turbine types and their selection and application in EM 1110-2-4205. Each turbine type has different operating characteristics and imposes a different set of generator design criteria to correctly match the generator to the turbine. For any turbine type, however, the generator

should have sufficient continuous capacity to handle the maximum horsepower available from the turbine at 100-percent gate without the generator exceeding its rated nameplate temperature rise. In determining generator capacity, any possible future changes to the project, such as raising the forebay level and increasing turbine output capability, should be considered. Figure 3-1 shows a typical capability curve for a hydroelectric generator.

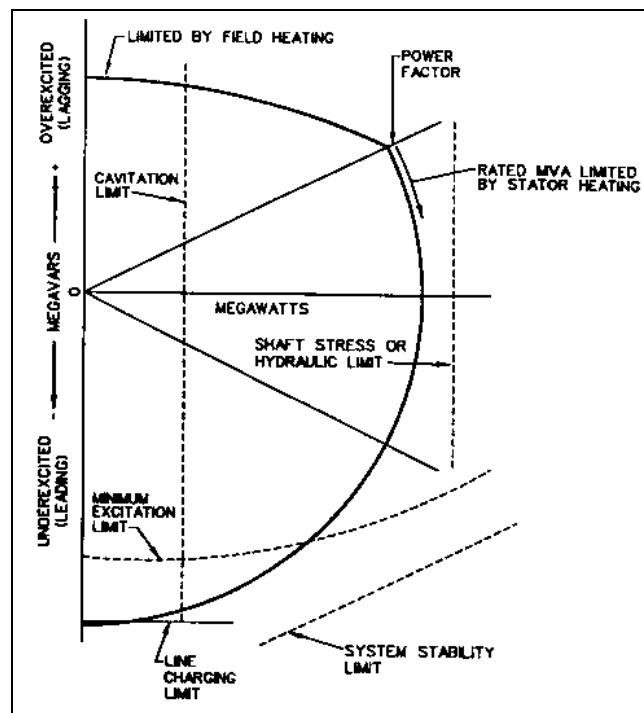


Figure 3-1. Typical hydro-generator capability curve

c. Generator voltage. The voltage of large, slow-speed generators should be as high as the economy of machine design and the availability of switching equipment permits. Generators with voltage ratings in excess of 16.5 kV have been furnished, but except in special cases, manufacturing practices generally dictate an upper voltage limit of 13.8 kV for machines up through 250 MVA rating. Based on required generator reactances, size, and Wk^2 , a lower generator voltage, such as 6.9 kV, may be necessary or prove to be more economical than higher voltages. If the generators are to serve an established distribution system at generator voltage, then the system voltage will influence the selection of generator voltage, and may dictate the selection and arrangement of generator leads also. Generators of less than 5,000 kVA should preferably be designed for 480 V, 2,400 V, or 4,160 V, depending on the facilities connecting the generator to its load.

d. Insulation.

(1) The generator stator winding is normally supplied with either Class B or Class F insulation materials, with the insulation system meeting the temperature limits and parameters of ANSI C50.12 (e.g., 75 °C rise above a 40 °C ambient). The choice of insulation system types depends on machine size, how the machine will be operated, and desired winding life. Modern hydro units are subjected to a wide variety of operating conditions but specifications should be prepared with the intent of achieving a winding life expectancy of 35 or more years under anticipated operating conditions.

(2) The choice between Class B or Class F insulation systems for the stator winding will depend on the expected use of the generator. If it will be operated continuously at or near rated load, or has a high probability of operating overloaded for longer than 2 hr at a time, then the Class F insulation system should be specified. For generators that can be expected to be operated below rated load most of the time, and at or near full load for only limited periods, a Class B insulation system would be satisfactory. An insulation system using a polyester resin as a binder should be considered a Class B system, since the softening temperature of polyester resin is close to the Class F temperature limit.

(3) Stator winding insulation systems consist of a groundwall insulation, usually mica, with a suitable insulation binder, generally a thermosetting epoxy or polyester material. These thermosetting systems achieve dielectric strengths equivalent to that of older thermoplastic insulation systems with less thickness than the older systems, allowing the use of additional copper in a given stator slot, achieving better heat transfer, and permitting cooler operation. Thermosetting insulation systems tolerate higher continuous operating temperatures than older systems with less mechanical deterioration.

(4) Polyester resin has a lower softening temperature (known as the glass transition temperature, T_g) than the more commonly available epoxy insulation system, but it has the advantage of being slightly more flexible than the epoxy system. This slight flexibility is an advantage when installing multi-turn coils in stator slots in small diameter generators. The plane of the coil side coincides with the plane of the slot once the coil is installed. During installation, however, the coil side approaches the slot at a slight angle so that the coil must be slightly distorted to make the side enter the slot. Polyester is less likely to fracture than epoxy when distorted during installation. Polyester has no advantage over epoxy if the stator

winding is of the Roebel bar type. Epoxy is usually preferred because of its higher T_g , and the polyester insulation system may not be available in the future.

(5) Thermosetting insulation system materials are hard and do not readily conform to the stator slot surface, so special techniques and careful installation procedures must be used in applying these materials. Corps guide specification CW-16210 provides guidance on types of winding and coil fabrication techniques, and installation, acceptance, and maintenance procedures to be used to ensure long, trouble-free winding life.

e. Short-circuit ratio.

(1) The short-circuit ratio of a generator is the ratio of the field current required to produce rated open circuit voltage, to the field current required to produce rated stator current when the generator output terminals are short-circuited. The short-circuit ratio is also the reciprocal of the per unit value of the saturated synchronous reactance. The short-circuit ratio of a generator is a measure of the transient stability of the unit, with higher ratios providing greater stability. Table 3-1 lists nominal short-circuit ratios for generators. Short-circuit ratios higher than nominal values can be obtained without much increase in machine size, but large values of short-circuit ratio must be obtained by trade-offs in other parameters of generator performance. Increasing the short-circuit ratio above nominal values increases the generator cost and decreases the efficiency and the transient reactance. Included in Table 3-1 are expected price additions to the generator basic cost and reductions in efficiency and transient reactance when higher than nominal short-circuit ratio values are required.

(2) In general, the requirement for other than nominal short-circuit ratios can be determined only from a stability study of the system on which the generator is to operate. If the stability study shows that generators at the electrical location of the plant in the power system are likely to experience instability problems during system disturbances, then higher short-circuit ratio values may be determined from the model studies and specified. If the power plant design is completed and the generators purchased prior to a determination of the exterior system connections and their characteristics, i.e., before the connecting transmission lines are designed or built, this will preclude making a system study to accurately determine the short-circuit ratio required. Where it is not feasible to determine the short-circuit ratio and there are no factors indicating that higher than nominal values are needed, then nominal short-circuit ratios should be specified.

Table 3-1
Generator Short-Circuit Ratios

	Short-Circuit Ratios				Price Addition (Percent of Basic Price)	Reduction in Full-Load Efficiency	Multiplier For Transient Reactance
	0.8PF	0.9PF	0.95PF	1.0PF			
Normal	1.00	1.10	1.07	1.25	0	0.0	1.000
Not More Than	1.08	1.22	1.32	1.43	2	0.1	0.970
Not More Than	1.15	1.32	1.46	1.60	4	0.2	0.940
Not More Than	1.23	1.42	1.58	1.75	6	0.2	0.910
Not More Than	1.31	1.52	1.70	1.88	8	0.3	0.890
Not More Than	1.38	1.59	1.78	1.97	10	0.3	0.860
Not More Than	1.46	1.67	1.86	2.06	12.5	0.4	0.825
Not More Than	1.54	1.76	1.96	2.16	15	0.4	0.790
Not More Than	1.62	1.84	2.03	2.23	17.5	0.4	0.760
Not More Than	1.70	1.92	2.11	2.31	20	0.4	0.730
Not More Than	1.76	1.98	2.17	2.37	22.5	0.5	0.705
Not More Than	1.83	2.05	2.24	2.44	25	0.5	0.680
Not More Than	1.89	2.11	2.30	2.50	27.5	0.5	0.655
Not More Than	1.96	2.18	2.37	2.56	30	0.5	0.630
Not More Than	2.02	2.24	2.42	2.61	32.5	0.6	0.605
Not More Than	2.08	2.30	2.48	2.67	35	0.6	0.580
Not More Than	2.13	2.35	2.53	2.72	37.5	0.6	0.560
Not More Than	2.19	2.40	2.58	2.77	40	0.6	0.540
Not More Than	2.24	2.45	2.63	2.82	42.5	0.7	0.520
Not More Than	2.30	2.51	2.69	2.87	45	0.7	0.500
Not More Than	2.35	2.56	2.74	2.92	47.5	0.7	0.480
Not More Than	2.40	2.61	2.79	2.97	50	0.7	0.460
Not More Than	2.45	2.66	2.83	3.01	52.5	0.7	0.445
Not More Than	2.50	2.71	2.88	3.06	55	0.7	0.430

f. Line-charging and condensing capacities. Nominal values for these generator characteristics are satisfactory in all except very special cases. If the generator will be required to energize relatively long EHV transmission lines, the line-charging requirements should be calculated and a generator with the proper characteristics specified. The line-charging capacity of a generator having normal characteristics can be assumed to equal 0.8 of its normal rating multiplied by its short-circuit ratio, but cannot be assumed to exceed its maximum rating for 70 °C temperature rise. Often it will be desirable to operate generators as synchronous condensers. The capacity for which they are designed when operating over-excited as condensers is as follows, unless different values are specified:

<u>Power Factor</u>	<u>Condenser Capacity</u>
.80	65 percent
.90	55 percent
.95	45 percent
1.00	35 percent

g. Power factor.

(1) The heat generated within a machine is a function of its *kVA* output; the capacity rating of a generator is usually expressed in terms of *kVA* and power factor. (Larger machine ratings are usually given in *MVA* for convenience.) The kilowatt rating is the *kVA* rating multiplied by the rated power factor. The power-factor rating for the generator should be determined after giving consideration to the load and the characteristics of the system that will be supplied by the generator. The effect of power factor rating on machine capability is illustrated in Figure 3-1.

(2) The power factor at which a generator operates is affected by the transmission system to which it is connected. Transmission systems are designed to have resistive characteristics at their rated transmission capacities. Consequently, a generator connected to a transmission system will typically operate at or near unity power factor during maximum output periods. During lightly loaded

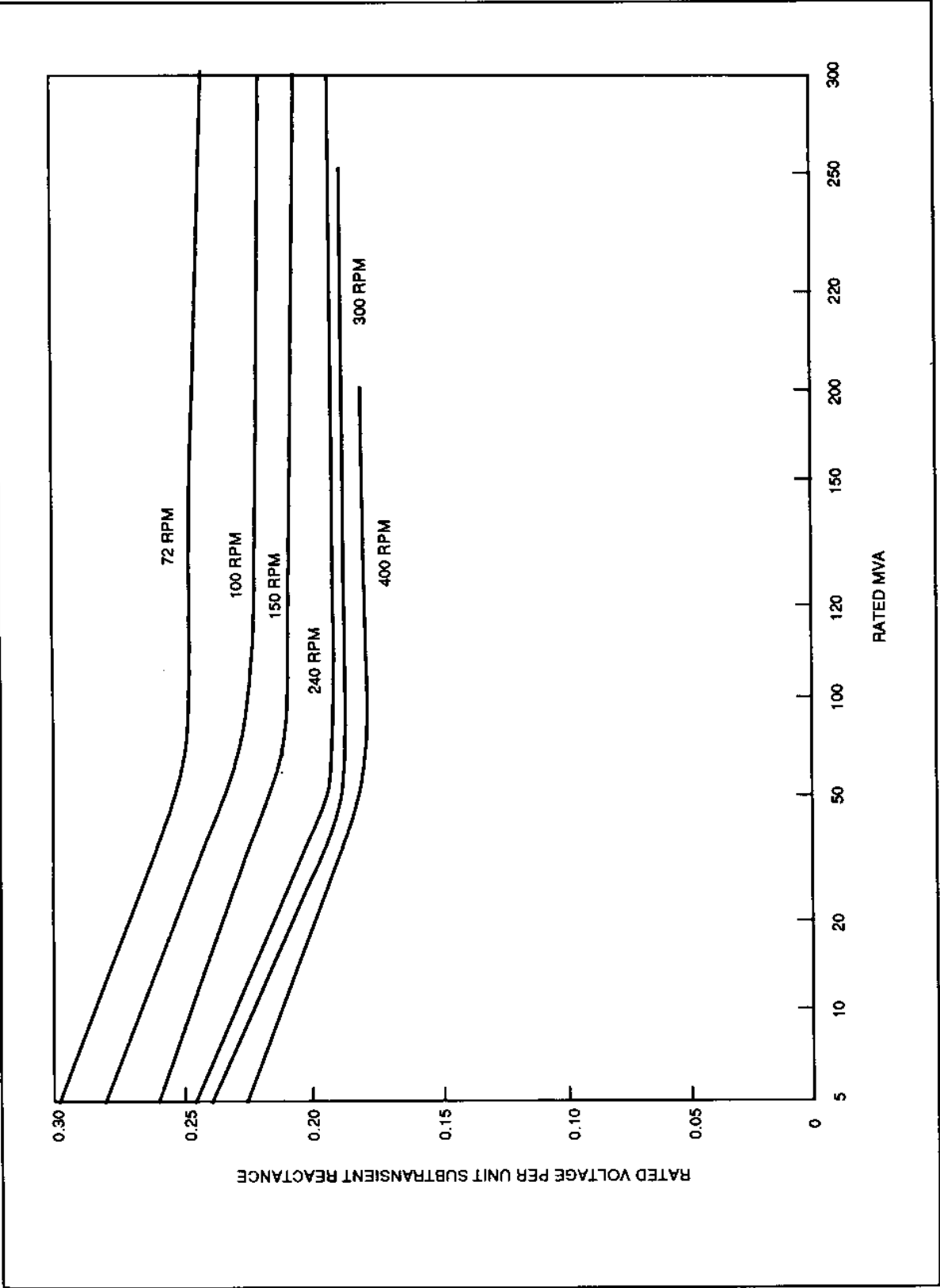


Figure 3-2. Typical generator transient reactances

conditions, however, the generator may be required to assist in transmission line voltage regulation. A generator operating on an HV transmission system with relatively short transmission distances will typically be required to supply reactive power (i.e., operate with a lagging power factor in an overexcited condition), due to the inductive characteristic of the unloaded transmission line. A generator operated on a long, uncompensated EHV transmission line will typically be required to absorb reactive power (i.e., operate with a leading power factor in an underexcited condition), due to the capacitive characteristic of the unloaded transmission line. In the latter case, the generator field current requirements are substantially below rated field currents, thus reducing the generator field strength. With reduced field strength, the generator operates closer to its stability limit (see Figure 3-1), making it more susceptible to loss of synchronism or pole slipping in the event of a system disturbance.

(3) It is highly desirable that the generator be designed for the power factor at which it will operate in order to improve system stability. In general, unless studies indicate otherwise, the power factor selected should be 0.95 for medium and large generators unless they will be at the end of a long transmission line, in which case a value approaching unity may be desirable.

h. Reactances.

(1) The eight different reactances of a salient-pole generator are of interest in machine design, machine testing, and in system stability and system stability model studies. A full discussion of these reactances is beyond the scope of this chapter, but can be found in electrical engineering texts (Dawes 1947; Fitzgerald and Kingsley 1961; Puchstein, Lloyd, and Conrad 1954), and system stability texts and standards (IEEE 399).

(2) Both rated voltage values of transient and subtransient reactances are used in computations for determining momentary rating and the interrupting ratings of circuit breakers. A low net through reactance of the generator and step-up transformer combined is desirable for system stability. Where nominal generator and transformer design reactances do not meet system needs, the increase in cost of reducing either or both the generator and transformer reactances and the selection of special generator reactance should be a subject for economic study. Such a study must include a consideration of space and equipment handling requirements, since a reduction in reactance may be accomplished by an increase in generator height or diameter, or both.

(3) Typical values of transient reactances for large water wheel generators indicated by Figure 3-2 are in accordance with industry standard practice. Guaranteed values of transient reactances will be approximately 10 percent higher.

(4) Average values of standard reactance will probably be sufficiently close to actual values to determine the rating of high-voltage circuit breakers, and should be used in preliminary calculations for other equipment. As soon as design calculations for the specific machine are available, the design values should be used in rechecking the computations for other items of plant equipment.

i. Amortisseur windings.

(1) Amortisseur windings (also referred to as damper windings in IEEE 399; Dawes 1947; Fitzgerald and Kingsley 1961; and Puchstein, Lloyd, and Conrad 1954) are essentially a short-circuited grid of copper conductors in the face of each of the salient poles on a waterwheel generator. Two types of amortisseur windings may be specified. In one, the pole face windings are not interconnected with each other, except through contact with the rotor metal. In the second, the pole face windings are intentionally connected at the top and bottom to the adjacent damper windings.

(2) The amortisseur winding is of major importance to the stable operation of the generator. While the generator is operating in exact synchronism with the power system, rotating field and rotor speed exactly matched, there is no current in the damper winding and it essentially has no effect on the generator operation. If there is a small disturbance in the power system, and the frequency tends to change slightly, the rotor speed and the rotating field speed will be slightly different. The rotor mass is perturbed when synchronizing power tends to pull the rotor back into synchronism with the system. That perturbation tends to cause the rotor-shaft-turbine runner mass to oscillate about its average position as a torsional pendulum. The result is relatively large pulsations in the energy component of the generator current. In worst case, the oscillations can build instead of diminishing, resulting in the generator pulling out of step with possible consequential damage.

(3) At the onset of the oscillations, however, the amortisseur winding begins to have its effect. As the rotating field moves in relation to the rotor, current is induced in the amortisseur windings. Induction motor

action results, and the rotor is pulled back toward synchronism by the amortisseur winding action.

(4) The amortisseur (damper) winding is of importance in all power systems, but even more important to systems that tend toward instability, i.e., systems with large loads distant from generation resources, and large inertia loads.

(5) In all cases, connected amortisseur windings are recommended. If the windings are not interconnected, the current path between adjacent windings is through the field pole and the rotor rim. This tends to be a high impedance path, and reduces the effectiveness of the winding, as well as resulting in heating in the current path. Lack of interconnection leads to uneven heating of the damper windings, their deterioration, and ultimately damage to the damper bars.

(6) The amortisseur winding also indirectly aids in reducing generator voltage swings under some fault conditions. It does this by contributing to the reduction of the ratio of the quadrature reactance and the direct axis reactance, X_q/X_d . This ratio can be as great as 2.5 for a salient pole generator with no amortisseur winding, and can be as low as 1.1 if the salient pole generator has a fully interconnected winding.

j. Efficiencies. The value of efficiency to be used in preparing the generator specification should be as high as can be economically justified and consistent with a value manufacturers will guarantee in their bids. Speed and power factor ratings of a generator affect the efficiency slightly, but the selection of these characteristics is governed by other considerations. For a generator of any given speed and power factor rating, design efficiencies are reduced by the following:

- (1) Higher Short-Circuit Ratio (see paragraph 3-2e).
- (2) Higher Wk^2 (see paragraph 3-5b).
- (3) Above-Normal Thrust.

Calculated efficiencies should be obtained from the supplier as soon as design data for the generators are available. These design efficiencies should be used until test values are obtained.

3-3. Generator Neutral Grounding

a. General. The main reasons for grounding the neutrals of synchronous generators are to limit overvoltages

on the generators and connected equipment under phase-to-ground fault conditions, and to permit the application of suitable ground fault relaying. Suitable neutral grounding equipment should be provided for each generator in hydroelectric power plants. The generator neutrals should be provided with current-limiting devices in the neutral circuits to limit the winding fault currents and resulting mechanical stresses in the generators in accordance with IEEE C62.92.2 requirements. Also, generator circuit breakers are designed for use on high impedance grounded systems, where the phase-to-ground short-circuit current will not exceed 50A. High impedance grounding with distribution transformers and secondary resistors is the method of choice for waterwheel generators.

b. Choice of grounding method. The choice of generator neutral grounding type for each installation, and the selection of the most suitable type and rating of neutral grounding equipment, should be made after preparation of fault current calculations and consideration of the following factors:

- (1) Limitation of winding fault current and resulting mechanical stresses in the generator.
- (2) Limitation of transient overvoltages due to switching operations and arcing grounds.
- (3) Limitation of dynamic overvoltages to ground on the unfaulted phases.
- (4) Generator surge protection (see paragraph 3-4).
- (5) Generator ground fault relaying (see paragraph 8-6b(3)).
- (6) Limitation of damage at the fault.
- (7) Neutral switchgear requirements.
- (8) Cost of neutral grounding equipment.

c. Solid neutral grounding. Solid neutral grounding is the simplest grounding method, since transient overvoltages and overvoltages to ground on the unfaulted phases during phase-to-ground faults are held to a minimum. Solid neutral grounding does produce maximum ground fault current and possible damage at the fault. Solid neutral grounding is not recommended.

d. Reactor neutral grounding. Reactor neutral grounding has certain desirable characteristics similar to those of solid neutral grounding. It is a preferred method

of grounding in cases where a neutral current-limiting device is required to meet ANSI/IEEE short-circuit requirements and where the ratio of the zero sequence reactance to the positive sequence subtransient reactance at the fault does not exceed 6.0. Reactor neutral grounding limits transient overvoltages and overvoltages to ground on the unfaulted phases to safe values where the above reactance ratio does not exceed approximately 6.0. However, in most hydro applications, this reactance ratio approaches or exceeds 6.0, and since the high impedance distribution transformer-secondary resistor system is more economical, reactor neutral grounding does not find widespread use in hydro applications.

e. Resistor neutral grounding. Resistor neutral grounding can be considered in cases where solid neutral grounding or reactor neutral grounding would not be satisfactory; where several generators are paralleled on a common bus, especially in the case of generators of small or medium kVA rating; and where there are no exposed overhead feeders supplied at generator voltage. The resistor is usually rated to limit the generator neutral current during a phase-to-ground fault to a value between 100 and 150 percent of the generator full-load current. Possible damage at the fault is thus materially reduced, yet sufficient ground fault current is available to permit the application of satisfactory and selective ground fault relaying. The technique does produce high voltage to ground, exposing insulation systems of equipment connected to the generator to the possibility of insulation failure.

f. Distribution transformer-secondary resistor neutral grounding.

(1) This is the preferred method of generator neutral grounding and is, in effect, high-resistance neutral grounding. This is the method used in most North American hydro installations because the cost of grounding devices and neutral switchgear for other grounding methods is excessive due to the large values of ground fault current. It is also applicable to generators connected directly to delta-connected windings of step-up power transformers, especially where there are no overhead feeders supplied at generator voltage. The characteristics of this method of grounding, with respect to transient overvoltages to ground on the unfaulted phases and the requirement for the use of ungrounded-neutral rated surge arresters for generator surge protection, are similar to those of resistor neutral grounding.

(2) With this method of grounding, the generator neutral current, during a phase-to-ground fault, is limited to a very low value, usually between 5A and 15A, by the

use of a relatively low-ohm resistor shunted across the secondary of a conventional step-down transformer whose primary is connected in the generator neutral circuit. The possible damage at the fault is therefore least of any of the various grounding methods. However, the type of generator ground fault relaying which can be applied has certain disadvantages when compared to the relaying which can be used with other grounding methods. Due to relatively low relay sensitivity, a considerable portion of the generator windings near the neutral ends cannot be protected against ground faults, the relaying is not selective, and the relay sensitivity for ground faults external to the generator varies greatly with the fault resistance and the resistance of the return circuit for ground fault current. The kVA rating of the grounding transformer should be based on the capacitive current which would flow during a phase-to-ground fault with the generator neutral ungrounded.

(3) Due to the relative infrequency and short duration of ground faults, a rating of 25 to 100 kVA is usually adequate for the transformer. The voltage rating of the transformer high-voltage winding should be equal to rated generator voltage, and the transformer low-voltage winding should be rated 240 V. The rating of the secondary resistor is based on making the resistor kW loss at least equal to the capacitive fault kVA.

g. Generator neutral equipment.

(1) An automatic air circuit breaker should be provided in the neutral circuit of each generator whose neutral is solidly grounded, reactor grounded, or resistor grounded. The circuit breaker should be a metal-clad, drawout type, either 1-pole or 3-pole, with a voltage rating at least equal to rated generator voltage, and with adequate ampere interrupting capacity, at rated voltage, for the maximum momentary neutral current during a single phase-to-ground fault. For generator neutral service, the circuit breakers may be applied for interrupting duties up to 115 percent of their nameplate interrupting ratings. When 3-pole breakers are used, all poles should be paralleled on both line and load sides of the breaker.

(2) A single-pole air-break disconnect should be provided in each generator neutral circuit using distribution transformer-secondary resistor type grounding. The disconnect should have a voltage rating equal to rated generator voltage, and should have the minimum available momentary and continuous current ratings. The disconnect, distribution transformer, and secondary resistor should be installed together in a suitable metal enclosure. The distribution transformer should be of the dry

type, and its specifications should require a type of insulation that does not require a heater to keep moisture out of the transformer.

3-4. Generator Surge Protection

a. Surge protection equipment. Since hydroelectric generators are air-cooled and physically large, it is neither practical nor economical to insulate them for as high impulse withstand level as oil-insulated apparatus of the same voltage class. Because of this and the relative cost of procuring and replacing (or repairing) the stator winding, suitable surge protection equipment should be provided for each generator. The equipment consists of special surge arresters for protection against transient overvoltage and lightning surges, and special capacitors for limiting the rate of rise of surge voltages in addition to limiting their magnitude.

b. Insulation impulse level. The impulse level of the stator winding insulation of new generators is approximately equal to the crest value of the factory low-frequency withstand test voltage, or about 40.5 kV for 13.8-kV generators. The impulse breakdown voltages for surge arresters for 13.8-kV generator protection are approximately 35 kV for 12-kV grounded-neutral rated arresters, and approximately 44 kV for 15 kV ungrounded-neutral rated arresters. Grounded-neutral rated surge arresters therefore provide better protection to generators than ungrounded-neutral rated arresters.

c. Grounded-neutral rated arresters. To correctly apply grounded-neutral rated arresters without an unacceptable risk of arrester failure, the power-frequency voltage applied across the arrester under normal or fault conditions must not exceed the arrester voltage rating. This requirement is usually met if the ratio of zero sequence reactance to positive sequence subtransient reactance at the fault, for a single phase-to-ground fault, does not exceed approximately 6.0. Since distribution transformer-secondary resistor grounding does not meet this requirement, only ungrounded-neutral rated surge arresters should be applied for generator surge protection.

d. Arrester arrangement. In most cases, one surge arrester and one 0.25-microfarad surge capacitor are connected in parallel between each phase and ground. In certain cases, however, such as the condition where the generators supply distribution feeders on overhead lines at generator voltage, or where two or more generators will be operated in parallel with only one of the generator

neutrals grounded, two of the above capacitors per phase should be provided. A separate set of surge protection equipment should be provided for each generator. The equipment should be installed in metal enclosures located as close to the generator terminals as possible.

3-5. Mechanical Characteristics

The section of Guide Specification CW-16120 covering mechanical characteristics of the generator provides for the inclusion of pertinent data on the turbine. Since generator manufacturers cannot prepare a complete proposal without turbine characteristics, the generator specification is not advertised until data from the turbine contract are available.

a. Speeds.

(1) Hydraulic requirements fix the speed of the unit within rather narrow limits. In some speed ranges, however, there may be more than one synchronous speed suitable for the turbine, but not for the generator because of design limitations.

(2) Generators below 360 *r/min* and 50,000 kVA and smaller are nominally designed for 100 percent overspeed. Generators above 360 *r/min* and smaller than 50,000 kVA are generally designed for 80 percent overspeed. Generators larger than 50,000 kVA, regardless of speed, are designed for 85 percent overspeed. Because of the high overspeed of adjustable blade (Kaplan) turbines, in some cases more than 300 percent of normal, it may be impracticable to design and build a generator to nominal design limitations. Where overspeeds above nominal values are indicated by the turbine manufacturer, a careful evaluation of the operating conditions should be made. Also, the designer should be aware that turbine and generator overspeed requirements are related to the hydraulic characteristics of the unit water inlet structures. Hydraulic transients that might result from load rejections or sudden load changes need to be considered.

(3) Generators for projects with Kaplan turbines have been designed for runaway speeds of 87-1/2 percent of the theoretical maximum turbine speed. In accordance with requirements of Guide Specification CW-16120, the stresses during design runaway speeds should not exceed two-thirds of the yield point. However, where the design overspeed is less than the theoretical maximum runaway speed, calculated stresses for the theoretical maximum speed should be less than the yield points of the materials.

b. Flywheel effect.

(1) The flywheel effect (Wk^2) of a machine is expressed as the weight of the rotating parts multiplied by the square of the radius of gyration. The Wk^2 of the generator can be increased by adding weight in the rim of the rotor or by increasing the rotor diameter. Increasing the Wk^2 increases the generator cost, size, and weight, and lowers the efficiency. The need for above-normal Wk^2 should be analyzed from two standpoints, the effect on power system stability, and the effect on speed regulation of the unit.

(2) Electrical system stability considerations may in special cases require a high Wk^2 for speed regulation. As Wk^2 is only one of several adjustable factors affecting system stability, all factors in the system design should be considered in arriving at the minimum overall cost. Sufficient Wk^2 must be provided to prevent hunting and afford stability in operation under sudden load changes. The index of the relative stability of generators used in electrical system calculations is the inertia constant, H , which is expressed in terms of stored energy per kVA of capacity. It is computed as:

$$H = \frac{kW \cdot s}{kVA} = \frac{0.231 (Wk^2) (r/min)^2 \times 10^{-6}}{kVA}$$

(3) The inertia constant will range from 2 to 4 for slow-speed (under 200 r/min) water wheel generators. Transient hydraulic studies of system requirements furnish the best information concerning the optimum inertia constant, but if data from studies are not available, the necessary Wk^2 can be computed or may be estimated from a knowledge of the behavior of other units on the system. Estimates of the effect of increased Wk^2 on the generator base cost are indicated by Figure 3-3.

(4) The amount of Wk^2 required for speed regulation is affected by hydraulic conditions (head, length of penstock, allowable pressure rise at surge tank, etc.) and the rate of governor action. The speed increase when full load is suddenly dropped should be limited to 30 to 40 percent of normal speed. This allowable limit may sometimes be increased to 50 percent if the economics of the additional equipment costs are prohibitive. When station power is supplied from a main generator, the effect of this speed rise on motor-driven station auxiliaries should be considered. Smaller generators servicing isolated load blocks should have sufficient Wk^2 to provide satisfactory speed regulation. The starting of large motors on such systems should not cause a large drop in the isolated system frequency.

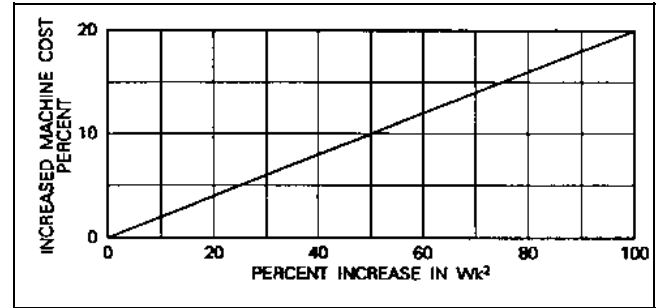


Figure 3-3. Effect of increased Wk^2 on generator cost (included by permission of Westinghouse Electric Corp)

(5) The measure of stability used in turbine and governor calculations is called the flywheel constant and is derived as follows:

$$\text{Flywheel Constant} = \frac{(Wk^2) (r/min)^2}{hp}$$

If the horsepower (hp) in this formula is the value corresponding to the kVA (at unity power factor) in the formula for the inertia constant (H), the flywheel constant will be numerically equal to 3.23×10^6 multiplied by the inertia constant. As the actual turbine rating seldom matches the generator rating in this manner, the flywheel constant should be computed with the above formula.

c. Cooling.

(1) Losses in a generator appear as heat which is dissipated through radiation and ventilation. The generator rotor is normally constructed to function as an axial flow blower, or is equipped with fan blades, to circulate air through the windings. Small- and moderate-size generators may be partially enclosed, and heated generator air is discharged into the generator hall, or ducted to the outside. Larger machines are enclosed in an air housing with air/water heat exchangers to remove heat losses.

(2) Open cooling systems are normally adequate for small- and medium-size generators (less than 10 MW). If special ventilating and air cleaning equipment is required to accommodate an open cooling system, the cost of these features should be compared against the cost of having a generator with a closed air recirculating system with air/water heat exchangers.

(3) An enclosed air housing with a recirculated air cooling system with air/water heat exchangers is preferred for units of 10 MW and larger. Cooling of the generator

can be more easily controlled with such a system, and the stator windings and ventilating slots in the core kept cleaner, reducing the rate of deterioration of the stator winding insulation system. The closed system also permits the addition of automatic fire protection systems, attenuates generator noise, and reduces heat gains that must be accommodated by the powerhouse HVAC system.

(4) Water-cooled heat exchangers used in a recirculated air cooling system consist of groups of thin-walled finned tubes with appropriate water boxes, valves, and headers. Standard air coolers are designed for 50-pound-per-square-inch (psi) working pressure, but can be supplied for 100-psi working pressure for a slightly higher price. The 100-psi rated coolers should be used where the hydraulic head of the cooling water source is greater than 100 ft. For best service, tube sheets of 90/10 Cu/Ni should be used for air and bearing lube oil coolers. The turbine spiral case is normally used as the cooling water source for projects with heads of up to 250 ft. Where project head exceeds approximately 250 ft, pumped systems using a tailwater source are preferred.

(5) The design pressure for the stator heat exchangers should be based on pump shut-off head if a pumped source of cooling water is used. Design pressure for spiral case cooling water sources should be based on maximum project pool level, plus a surge allowance. Heat exchanger hydrostatic tests should be performed at pressures of 150 percent of rated pressure. Design cooling water temperature should be the maximum temperature of the cooling water source, plus a contingency allowance.

(6) The water supply line to the air coolers should be separate from the water line to the thrust-bearing cooler. It may prove desirable to modulate the water flow to the air coolers to control the generator temperature, or to shut it off entirely when the unit is being stopped. It is desirable to keep a full flow of water through the thrust bearing oil cooler whenever the unit is turning. Each cooling water supply line should be equipped with a flow indicator. The flow indicator should be equipped with an alarm contact for low flow.

(7) Each air cooler should be equipped with water shut-off valves so a cooler can be cut out if in trouble, or be serviced while the generator is operating. Coolers should be designed with as great a number of heat exchanger tubes in the air flow passage as practical in order to reduce water usage. Adequate floor drains inside the air housing should be provided to remove any water

that may condense on or leak from the coolers. The unit drain header should empty into the tailwater if plant conditions permit, but the drain should not be terminated where it will be subject to negative pressures from the draft tube, since this will impose negative pressures on the heat exchangers.

(8) Heated air from the generator enclosure should not be used for plant space heating because of the possibility of exposure of plant personnel to ozone, and the possibility of CO₂ being discharged into the plant. Water from the coolers may be used as a heat source in a heat pump type of heating system, but if water flow modulation is used, there may not be enough heat available during periods of light loading, or when the plant is shut down.

d. Weights and dimensions.

(1) Estimating weights and dimensions of the generators should be obtained from generator manufacturers for plant design purposes. These figures should be rechecked after bid data are available on the particular generator selected. The contemplated speed, Wk^2 , short-circuit ratio, reactance, and over-speed are the usual factors that have the greatest effect on weight variation. Where a high value Wk^2 is required, a machine of the next larger frame size with consequent increase in diameter may be required.

(2) Dimensions of the rotor and the method of assembling the rotor and the shaft in the generator have an important bearing on crane clearances. The number and location of air coolers and the shape of the air housing on a generator with the closed type of cooling system should be studied for their effect on the dimensions of the generator room. Generator and turbine access should be considered, as well as the possible need for suppressing noise radiated into the powerhouse.

3-6. Excitation Systems

a. General. Current practice in the design of Corps of Engineers power plants is to use solid state bus-fed excitation systems for the generator exciter and voltage regulator function. Solid state excitation systems currently available from reputable manufacturers exhibit reliability comparable to, and in some cases better than, older mechanical systems. Excitation system specifications should be carefully prepared, with attention to requirements of the power system to which the generator will be connected.

b. Large generators.

(1) The stability of a large turbine-generator set while connected to its power system is critically important. However, the designer must also consider the unit's characteristics when operating alone, or in an isolated "island" much smaller than the normal power system.

(2) One example of a unit operating alone is a main unit serving as the station service source in a plant that becomes separated from its power distribution system. The unit will have to accept motor starting loads, and other station service demands such as gate and valve operation, while maintaining a safe and stable output voltage and frequency. All this will be accomplished while operating at a fraction of its rated output.

(3) When operating in an "island," the unit may be required to operate in parallel with other units while running at speed-no-load in order to provide enough capacity to pick up blocks of load without tripping off line. In this case, stable operation without the stabilizing effect of a very large system is critically important to restoring service, and putting the system back together.

c. Small units. For small units producing energy for a very large system, stability is not so critical since system voltage support will be beyond the small unit's capability. Nonetheless, for its own safe operation, good voltage control is important. An extremely high response system is not necessary, but the system should respond rapidly enough to prevent dangerous voltage excursions.

d. Excitation system characteristics.

(1) In general, there are two types of static excitation systems: one using a full-inverting power bridge, and the other using a semi-inverting power bridge. The full-inverting system uses six (or more) silicon controlled rectifiers (SCRs) in the power bridge so the generator field voltage can be forced both positive and negative. The semi-inverting system allows the generator field voltage to be forced positive, and reduced to zero.

(2) The full-inverting bridge allows boost and buck operation much like that available in older systems, but with the potential for a faster response. Faster response means less phase shift in the control action, and the reduction of phase shift permits control action to increase the stability of voltage regulation (see also paragraph 3-6g(6)).

(3) Dips in output voltage can be reduced, and voltage recovery speed improved, with the field forcing function. Increasing the field voltage helps greatly in overcoming the lag caused by the inductance of the generator field, and increases the speed of response of generator output voltage to control action. However, the exciter ceiling voltage (maximum forcing voltage available) to the generator field must be limited to a value that will not damage field insulation. The manufacturer will determine the exciter ceiling voltage based on the nominal response specified.

(4) The semi-inverting system also provides for fast response, but without the capability to force the field voltage negative with respect to its normal polarity. This slows the generator output voltage response capability. One or more diodes provide a path for decaying field current when the AC contactor is opened.

(5) Power system requirements and machine voltage performance during unit load rejections should be considered in evaluating the use of a semi-inverting system. If stability requirements can be met and adequate voltage performance maintained during unit load rejections, then either a semi-inverting or a full-inverting system is acceptable. If either criterion appears compromised, a full-inverting system is recommended.

(6) If the particular generator (or plant) in question has sufficient capacity to affect the control area to which it is connected, a full-inverting voltage regulating system would be justified if the control area has a high ratio of energy import (or export) to load, and is marginally stable or experiences tie line separations. A full-inverting system can force voltage down if an export tie line is lost, and can force generator voltage down if the machine is suddenly tripped off line while carrying a substantial load. Both cases will reduce voltage stresses on the generator; the first example will assist in maintaining system stability, the second will help protect the generator windings from dangerous overvoltages.

e. Excitation system arrangement.

(1) In general, bus-fed solid state excitation systems are made up of three elements: the power potential transformer (PPT), the power bridge (or rectifier), and the control section (voltage regulator function).

(2) Location of the PPT will depend on the supply source chosen. If power to the PPT is supplied from the

generator leads, the bus arrangement will be affected, and that must be considered in the initial design and layout of the powerhouse. If the PPT is fed from the generator delta bus, its location must be selected so that it will be reasonably close to the power bridge equipment. The PPT should be specified to be self-cooled, and the designer should consider this in determining its location.

(3) For either power source to the PPT, protection should be provided by current-limiting fuses. The available fault current at the input to the PPT will be quite large, so it will be necessary to limit it to prevent destructive releases of energy at the fault location. Current-limiting fuses also provide circuit clearing without current surges that can cause voltage transients which are dangerous to the integrity of the generator insulation. When the fusible element melts, the fuse essentially becomes a resistor in series with the fault. Voltage and current across the resistor are thus in phase, and the circuit is cleared at the first zero crossing, without danger of arc restrike (if the fuse works properly).

(4) The excitation system should also provide for a means of disconnecting power from the generator field. In general, this requires that power be interrupted at the bridge input, at the generator field input, or at both places, and that a means of dissipating energy stored in the field be provided. Energy dissipation is a major consideration, because without it the field inductance will cause field voltage to rise sharply when field current is interrupted, possibly rupturing the field insulation. Several methods exist to perform the field removal function.

(a) One method of field removal for a semi-inverting system uses a contactor in the AC input to the power bridge. For field discharge, a diode (called a free-wheeling diode) can be used to provide a path for the field current to dissipate field energy. Another method is to provide a shorting contact in series with a discharge resistor across the generator field. When the Device 41 AC breaker opens, the auxiliary Device 41 shorting contact closes.

(b) A method which can be used with a full-inverting bridge uses a field breaker and discharge resistor. This is a straightforward method where the power from the bridge to the field is interrupted, and the field is simultaneously short-circuited through a discharge resistor.

(c) With either a semi- or full-inverting bridge, it is possible to use a device 41 in the DC side of the bridge, with a thyristor element to control field energy dissipation. The thyristor device is a three- (or more)

junction semiconductor with a fast OFF to ON switching time that is capable of going to the conducting state within a very short time (about one quarter of a cycle) after the Device 41 opens.

(d) With either a semi- or full-inverting bridge, it is possible to use a device 41 in the AC (input) side of the bridge, with a thyristor element to control field energy dissipation. The thyristor device is a three- (or more) junction semiconductor with a fast OFF to ON switching time that is capable of going to the conducting state within a very short time (about one quarter of a cycle) after the Device 41 opens.

(5) Power bridge equipment should be housed in a cubicle by itself, for safety and reduction of electromagnetic noise, and be located near or beside the excitation control cubicle. Both cubicles should be designed for reduction of radiated electromagnetic interference (EMI).

(6) The power electronics equipment in the excitation system can be either fan-cooled or self-cooled. Fan-cooled excitation systems are usually smaller than self-cooled systems, but require extra equipment for the lead-lag fan controls. Fan-cooled excitation systems may require additional maintenance resulting from such things as fans failing to start, air flow switches failing, fan air flow causing oil from the turbine pit to be deposited on filters, and worn-out fan motors causing noise to be applied to the regulator control system. Self-cooled excitation systems may require larger cubicles and higher-rated equipment to allow for heat transfer. On large generators, it may not be practical to use a self-cooled system. On smaller units it may be preferable. Each unit should be judged on its life cycle costs.

(7) If the capability of connecting a unit to a de-energized transmission system will be necessary ("black start" capability), there may be a requirement for operating the generator at around 25 percent of nominal voltage to energize transformers and transmission lines without high inrush currents. This requirement may impose the need for an alternate power source to the PPT since the power bridge might not operate reliably at reduced voltage levels. If an alternate supply source is needed, provide switching and protection, and ensure that the normal PPT source and the emergency source cannot be connected in parallel. The power transmission authority should be consulted to determine the voltage necessary for charging lines and transformers to re-energize a power system. Requiring additional power sources not only adds costs to the project, but complexity to the system, which may not be justified. The complexity of a system is

usually proportional to its maintenance, failure, and misoperation rate.

f. Excitation system regulators.

(1) The voltage regulator function of modern solid state excitation equipment is an integral part of the system, and will use digital control elements with microprocessor-based control. This type of control provides far more flexibility in changing regulator characteristics than the older mechanical element type of control. It also provides more precise and predictable control action, and will require far less maintenance.

(2) The voltage regulator function should provide automatic and manual control of generator output voltage, with “bumpless” transfer between modes, over a range of at least plus or minus 10 percent from nominal generator voltage. The bumpless transfer requirement means that the regulator control modes must track each other so that when the control mode is switched the generator voltage (or reactive output) will not exhibit a step change of any magnitude.

(3) Voltage regulator control to maintain generator power factor, or maintain a selected var loading may also be required. If the plant is to have an automatic control system, provisions should be required for control inputs to the regulator, and it may be possible to dispense with some of the regulator control features, particularly if the plant will not be manned.

g. Excitation system accessories.

(1) An AC input voltmeter, a DC output (field voltage) voltmeter, and a DC field ammeter are accessories that should be considered essential for a quick check on system operation. Rectifier failure detection should also be considered, particularly for units controlled remotely.

(2) Remotely operated controls are also essential for units controlled from locations remote from the unit switchboards. Maximum and minimum excitation limiter equipment should also be provided in all cases. This equipment is critical to units that are direct connected with other units on a common bus.

(3) Momentary connection of a DC source of proper polarity to the generator field (field flashing) should also be required. Field flashing provides prompt and reliable buildup of generator voltage without reliance on residual magnetism. Include protection against overlong application of the flashing source. The simplest source for field

flashing voltage is the station battery. If the unit is not required to have black start capability, an alternative to using the station battery is to use an AC power source with a rectifier to furnish the necessary DC power for field flashing. This alternative source could be considered if it is determined to be significantly more economical than providing additional station battery capacity. Depending on the design, this alternative could require additional maintenance in the long term for short-term cost reductions. Project life cost should be considered when evaluating the sources of field flashing. A rectifier can be used as the DC source if the station battery size can be reduced enough to provide economic justification.

(4) Reactive droop compensation equipment is needed for units operated in parallel on a common low-voltage bus to prevent unequal sharing of reactive load. Reactive droop compensation reduces the generator output voltage slightly as reactive output increases. The net effect is to stabilize unit operation when operating in parallel and tending to prevent var load swings between units.

(5) Active droop compensation (or “line drop” compensation) is simply a means of artificially relocating the point where the generator output voltage is sensed for the voltage regulation function. It consists of increasing the generator output voltage in proportion to output current, to compensate for the voltage drop between the generator output terminals and the desired point on the system. Active droop compensation should be considered if the generator is connected to the system through a high impedance unit transformer or to a long high-impedance transmission line. Line drop compensation is usually not required unless needed for power transmission system voltage stability. This requirement will be established by the power transmission authority. When used with automatic voltage control that derives its controlled-value input from the same, or nearly the same, point as the line drop compensation feature, caution should be used to ensure that the automatic voltage control system is not counteracting the effects of the voltage regulator line drop compensation feature. Close coordination with the power transmission authority is required to ensure power system voltage stability.

(6) Power System Stabilizer (PSS) equipment should be used on generators large enough to have a positive effect on power system stability. The PSS function tends to damp out generator rotor oscillations by controlling the excitation system output in phase opposition to power system oscillations to damp them out. PSS works by sensing an input from the power system and reacting to

oscillations in the power system. These oscillations typically show up in the unit as rotor angle oscillations and if allowed to continue to build up in conjunction with other synchronous machines in the system, set up unacceptable power swings between major loads and major generating plants in a widely dispersed power distribution grid.

h. Excitation system instrument transformers. Dedicated current and potential transformers should be supplied to service the excitation system voltage regulators. They can often be advantageously mounted in metal-clad switchgear, cubicles, or metal-enclosed bus runs, where they are associated with similar instrument transformers for metering and relay service. The latter are furnished and mounted by the manufacturer of the cubicles or buses, and a better layout can usually be devised, where all instrument transformers are of the same general form, than would result if space were provided for field installation of transformers supplied with the voltage regulator. Multiple-secondary current transformers save considerable space. The guide specifications provide for alternate methods of procurement, assuming that the general design of buses and generator leads will have been determined before the generator is awarded.

3-7. Generator Stator

a. Stator core stampings. The stator primary component is the thin sheet steel stampings that, when stacked together and clamped, form the stator core. The stamping shapes are so designed that when they are correctly stacked, they will form stator winding coil slots, with no stamping protruding into the slot. Uneven slots are detrimental to coil life in several ways: wear on ground wall insulation armor tape; prevention of adequate tightening of coil in the slot; and, in extreme cases, erosion of the ground wall insulation.

b. Stator frame.

(1) The stator frame is designed for rigidity and strength to allow it to support the clamping forces needed to retain the stator punchings in the correct core geometry. Strength is needed for the core to resist deformation under fault conditions and system disturbances. Also, the core is subjected to magnetic forces that tend to deform it as the rotor field rotates. In a few large size machines, this flexing has been known to cause the core to contact the rotor during operation. In one instance, the core deformed and contacted the rotor, the machine was tripped by a ground fault, and intense heating caused local stator tooth iron melting, which damaged the stator winding ground wall insulation.

(2) Even if the rotor and the stator core do not come in contact, the varying air gap is a problem. In machines with split phase windings where the split phase currents are monitored for machine protection, the variation in the air gap causes a corresponding variation in the split phase currents. If the variations are significant, the machine will trip by differential relay action, or the differential relays will have to be desensitized to prevent tripping. Desensitizing the relays will work, but it reduces their effectiveness in protecting the machine from internal faults.

(3) Further reading on this subject can be found in the IEEE Transactions on Power Apparatus and Systems, Vol PAS-102, Nos. 9 and 10, and in the AIEE Transactions of October 1953, as Paper 53-314.

c. Stator assembly. Small stator assemblies that can be shipped in one or two pieces should be completely assembled at the factory. If the stator frame assembly has to be shipped in more than two pieces, the core should probably be stacked in the field. Field stacking will avoid splits in the stator core, the major source of stator core problems. Stator frames are generally built at the factory in sections that are as large as can be shipped to the erection site. Stator assembly is completed in the field by bolting the sections together, stacking the core iron laminations, and winding the stator. Field stacking of the stator core results in a higher initial cost for the generator, but provides better service life and is preferred. Generator Guide Specification CW-16120 contains a discussion on stator assembly.

d. Multiturn coil stator windings. On smaller generators, and on certain sizes of larger machines, stator windings employing multiple turn coils are used. This effectively inserts more coils per armature slot, giving a higher generated voltage per slot as compared with a single turn bar winding. With this winding design, the stator winding is divided into two or more parallel paths per phase. On the neutral ends of the winding, one half of each phase is connected to the ground point through a current transformer (CT) of carefully selected ratio and characteristics. On the generator output, other CTs measure the total phase current. Differential relays compare the split phase current and total phase current; an internal generator fault that results in unbalanced current between the phase halves can usually be detected and the unit tripped off quickly enough to prevent serious damage.

e. Roebel bar stator windings. For large generators, winding designs using single turn coils are preferred, in which case the neutral terminals are not divided and a

different arrangement of CTs for the differential relays is required. The single turn coils use a Roebel transposition, rather than separate turns, to balance current in the conductors. This eliminates the possibility of turn-to-turn faults, which are a common cause of winding failures. Single turn coils cannot be used on machines with short bore heights because there is not sufficient room to make the Roebel transposition. There are also certain configurations of large machines which do not allow the use of single turn coils.

3-8. Rotor and Shaft

a. Rotor assembly.

(1) Large generator rotors must be assembled in the powerhouse. Manufacturing practice provides two types, one in which the hub and arms are made of cast steel, the other with a cast or fabricated hub to which are bolted and keyed the fabricated rotor arms. For rotors with bolted-on arms, a means of access to inspect and re-tighten the bolts should be specified. Some medium-sized units have been built with rotors of stacked sheets, but this type is limited by the rolling width of the sheets. With both types the rotor rim is built up of sheet steel punchings.

(2) Pole pieces, assembled and wound in the factory, are usually made with a dovetail projection to fit slots in the rim punchings. The pole pieces are assembled to the rotor using wedge-shaped keys, two keys per pole piece. The field assembly program should make provisions for handling large pole pieces without tying up the powerhouse bridge crane.

b. Generator shafts.

(1) Generator shafts 12-in. and larger diameter should be gun-barrel drilled full length. This bore facilitates inspection of the shaft forging, and in the case of Kaplan units, provides a passage for the two oil pipes to the blade servo-motor in the turbine shaft.

(2) Generators designed with the thrust bearing located below the rotor usually have either a bolted connection between the bottom of the rotor hub and a flange on the shaft, or the shaft projects through a hole in the hub and is keyed to it. Provisions in the powerhouse for rotor erection should consider the floor loading of the rotor weight, concentrated on the area of the shaft hub or the rotor flange, supported by the powerhouse floor. Include a plate in the floor (included with the generator specifications and to be supplied by the generator

manufacturer) to which the rotor hub or shaft flange can be bolted.

(3) If the design of the rotor and shaft provides for a permanent connection between the shaft and rotor hub, it may be necessary to locate the rotor erection plate in a floor recess, or on a pedestal on the floor below the erection space, under a hole in the floor provided for the shaft. Also, if the complete rotor is to be assembled on a long shaft which extends below the rotor hub before the shaft and rotor are placed in the stator, it may be convenient to provide a hole in the erection floor so that the lower end of the shaft will rest on the floor below, thus minimizing the crane lift during rotor assembly. When the shaft must be handled with the rotor in assembling the generator, the crane clearance above the stator frame may be affected.

3-9. Brakes and Jacks

The brakes, which are used to stop rotation of the unit, are actuated by 100-psi air pressure and are designed to serve as rotor jacks when high-pressure oil is substituted for air. As far as the generator alone is concerned, the distance the rotor is to be lifted by the jacks depends on the space required to change a thrust bearing shoe. Blocks should be provided to hold the rotor in the raised position without depending on the jacks. The usual lift required to service a bearing is approximately 2 in. If the generator is to be driven by a Kaplan turbine, the lift must provide space for disconnecting the Kaplan oil piping. This lift may be as much as 12 in. The generator manufacturer can usually design for this extra lift so nothing on the generator need be disturbed except to remove the collector brush rigging. Motor-operated jacking oil pumps can be permanently connected to large units. Medium-sized and smaller generators can be served with a portable motor-operated oil pump. Motor-operated pumps should be provided with suitable oil supply and sump tanks so the oil system will be complete and independent of the station lubricating oil system.

3-10. Bearings

a. Thrust bearing loading. The thrust bearing in the generator is the most important bearing element in the generator-turbine assembly as it carries not only the weight of the rotating generator parts, but the weight of the turbine shaft and turbine runner, in addition to the hydraulic thrust on the runner. The allowable hydraulic thrust provided in standard generator design is satisfactory for use with a Francis runner, but a Kaplan runner requires provision for higher-than-normal thrust loads. It

is important that the generator manufacturer have full and accurate information regarding the turbine.

b. Thrust bearing types. The most commonly used types of thrust bearings are the Kingsbury, the modified Kingsbury, and the spring-supported type. The spherical type of thrust bearing has not been used on any Corps of Engineers' generators. All of these types have the bearing parts immersed in a large pot of oil that is cooled either by water coils immersed in the oil or by the oil pumped through a heat-exchanger mounted near the bearing. These various types of bearings are fully described in available texts, such as "The Mechanical Engineers' Handbook" (Marks 1951) and "Mechanical Engineers' Handbook" (Kent 1950).

c. Thrust bearing lubrication. The basic principle of operation of all bearing types requires a film of oil between the rotating bearing plate and the babbitted stationary shoes. The rotating parts on some machines are so heavy that when the machine is shut down for a few hours, the oil is squeezed out from between the bearing surfaces and it is necessary to provide means to get oil between the babbitted surface and the bearing plate before the unit is started. Specifications for generators above 10 MW, and for generators in unmanned plants, should require provisions for automatically pumping oil under high pressure between the shoes and the runner plate of the thrust bearing just prior to and during machine startup, and when stopping the machine.

d. Guide bearings. A guide bearing is usually provided adjacent to the thrust bearing and is lubricated by the oil in the thrust bearing pot. Except for Kaplan units, machines with guide bearings below the rotor seldom require an upper guide bearing. When the thrust bearing is above the rotor, a lower guide bearing is required. Two guide bearings should always be provided on generators for use with Kaplan turbines. These separate guide bearings have self-contained lubricating systems. Oil in the bearings seldom needs to be cleaned or changed, but when cleaning is necessary, the preferred practice is to completely drain and refill the unit when it is shut down. Valves on oil drains should be of the lock-shield type to minimize possibility of accidental draining of the oil during operation.

3-11. Temperature Devices

a. Types of temperature devices. All generator and turbine bearings are specified to have three temperature sensing devices: a dial-type indicating thermometer with adjustable alarm contacts, embedded resistance

temperature detector (RTD) devices, and a temperature relay (Device 38). The dial portions of the indicating thermometers are grouped on a panel which can be part of the governor cabinet, mounted on the generator barrel, or on another panel where they can be easily seen by maintenance personnel or a roving operator.

b. Dial indicator alarms. The dial indicator alarm contacts are set a few degrees above the normal bearing operating temperatures to prevent nuisance alarms. When approaching their alarm setpoint, these contacts tend to bounce and chatter. If they are used with event recorders, they can produce multiple alarms in rapid succession unless some means are used to prevent this.

c. RTDs. RTD leads are brought out to terminal blocks, which are usually mounted in the generator terminal cabinet on the generator air housing. Turbine bearing RTD leads should be terminated in the same place as the generator RTD leads. For bearings equipped with more than one RTD, it is usually adequate to monitor only one, and let the other(s) serve as spares. Thrust bearings may have six or more RTDs. Monitoring three or four of them is usually satisfactory. Generator stator windings usually have several RTDs per phase. On the larger machines, monitor two RTDs per phase, and keep the remainder as spares.

d. RTD monitoring. How the RTDs are used depends partly on the decisions made about the plant control system. They can be scanned by the analog input section of a remote terminal unit (RTU) if the plant is controlled remotely, or they can be used as inputs to a local stand-alone scanner system, with provisions for remote alarms and tripping the unit on high temperatures. In any case, permanent records of bearing temperatures are no longer retained.

e. Control action. Whether to alarm or trip on RTD temperature indication depends on other decisions about how the plant will be controlled, and what kind of control system is used. For automated plants, stator temperature increases can be used as an indication to reduce unit load automatically, for instance.

f. Air temperature indicators. Air temperature indicators in air cooler air streams are used to balance the cooling water flow, and to detect cooler problems. Air temperature alarms should be taken to the control point, or input to the plant control system if the plant is automated.

g. *Temperature relays.* Temperature relays are typically used to shut the unit down on high bearing temperatures, 105 °C or so. Separate contacts should also be provided for alarming. Note that once a bearing temperature reaches the trip point, the damage has been done. It is almost never possible to save the bearing. Tripping the unit promptly is done to save damage to other parts of the unit resulting from failure of the bearing. Temperature relay alarm points should be taken to the annunciator, and to the RTU or plant control system. It is not necessary to provide sequence of event recording for the Device 38 because the bearing temperature event is such a slow process.

3-12. Final Acceptance Tests

a. *General.* Because of the size of water wheel generators, they are normally assembled in the field, and because of their custom design, it is advisable to perform a series of acceptance and performance tests on the generators during and following their field assembly. The purpose of these tests is to ensure that the units meet contractual performance guarantees, to provide a quality control check of field assembly work, and finally to provide a “bench mark” of “as-built” conditions serving as an aid in future maintenance and repair activities. Certain field tests are performed on every generator of a serial (multi-unit) purchase; other tests are performed on only one unit of the serial purchase, e.g., tests for ensuring conformance with contractual guarantees.

b. *Field acceptance tests and special field tests.* These tests are as follows:

(1) Field quality control tests (all units). A series of dielectric and insulation tests for the stator and field windings, performed during field work, including turn-to-turn tests, coil transposition group tests, and semiconducting slot coating-to-stator iron resistance tests, to monitor field assembly techniques.

(2) Field acceptance tests (all units). These tests consist of:

(a) Stator dielectric tests. These tests consist of: Insulation resistance and polarization index, Corona probe test, Corona visibility test, Final AC high potential test, Partial discharge analysis (PDA) test, and Ozone detection (optional).

(b) Rotor dielectric tests.

(c) Stator and rotor resistance tests.

(3) Special field test (one unit of serial). These tests consist of:

(a) Efficiency tests.

(b) Heat run tests.

(c) Machine parameter tests.

(d) Excitation test.

(e) Overspeed tests (optional).

c. *Testing considerations.*

(1) Planning for tests on the generator after its installation should begin prior to completion of the generator specifications. Any generator that must be assembled in the powerhouse will require field testing after installation to measure values of efficiency and reactances, particularly when efficiency guarantees are included in the purchase specifications. The generator manufacturer performs these tests with a different crew from those employed for generator erection. Specification CW 16120 requires a second generator in the powerhouse with special switching equipment and “back-fed” excitation system to permit performing retardation tests used to determine generator efficiency. In addition, special arrangements are required to use one of the generator-voltage class breakers as a shorting breaker during sudden short-circuit tests.

(2) The manufacturer requires considerable advance notice of desirable testing dates in order to calibrate test instruments and ship in necessary switchgear and excitation equipment. If the associated turbine is to be given a field efficiency test, it may be desirable to coordinate the turbine and generator tests so that the electrical testing instruments will be available to measure generator output during the turbine test. The heat run requires a load on the generator. Normally, the generator is loaded by connecting the generator output to the system load. If system load isn't sufficient to load the generator, IEEE 115 outlines alternative techniques to simulate load conditions.

(3) The testing engineer may elect to use the plant instrument transformers instead of calibrated current and potential transformers if reliable data on plant instrument transformers are available.

(4) Generator erectors usually apply dielectric tests on the armature (stator) and field windings before the rotor is put into the machine. If the stator is wound in the field, a high potential test is usually done once each

day on all of the coils installed during that day. This facilitates repairs if the winding fails under test and may preclude missing scheduled “on-line” dates. The test voltages for these intermediate tests must be planned so that each one has a lower value than the previous test, but greater than the test voltage specified for the final high potential test.

(5) IEEE 43 describes the polarization index test. This index is the ratio of the insulation resistance obtained with a 10-min application of test voltage to that obtained with a similar application for a 1-minute period. Recommended indices and recommended insulation resistance values are also given in the referenced standard.

(b) Because of the relatively small amount of insulation on the field windings, simple insulation (Megger) tests are adequate to determine their readiness for the high-voltage test. Guide Specification CW-16120 requires the dielectric test to be made with the field winding connected to the collector rings and hence the test cannot be made until after the generator is assembled with the DC leads of the static excitation system connected.

3-13. Fire Suppression Systems

Generators with closed air recirculation systems should be provided with automatic carbon dioxide extinguishing systems. See Chapter 15 of EM 1110-2-4205 for details. On larger open ventilated generators, water spray installations with suitable detection systems to prevent false tripping should be considered.